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Abstract

Market power often emerges in wholesale electricity markets. Regulators use several strategies to limit market power: adopting bidding rules, compulsory forward markets and enhancing demand response. We study the case of the Irish Single Electricity Market (SEM), where the market will eliminate strict bidding rules to comply with the European Target Electricity Model. Using the PLEXOS unit-commitment model, we simulate the price that emerges in Cournot competition and find that it is more than 60% higher than in perfect competition. We then study how much the price varies with three measures that influence market power. Limiting thermal generators' ownership of wind generation does not affect prices. Forcing the largest firm to sell some of its output forward decreases prices, but keeps them well above competitive levels. The most effective measure is an increase in price elasticity of demand, although existing evidence shows that it is hard to achieve. We conclude that regulatory oversight of bids will have to continue, although the Target Model will be associated with limited transparency, creating further challenges.

Keywords: regulation; oligopoly; wind generation; forward contracts; demand response.

JEL classification: L1; L9.

1 Introduction

Wholesale electricity markets often have a small number of large generators, a feature that facilitates market power. Market power is likely in electricity markets due to the lack of economic storage, limitations to the amount of electricity that can flow along transmission and distribution lines, high capital costs of new generation and the limited reaction of electricity demand to price changes. Regulatory authorities confront the issue of how to mitigate market power under these conditions.

Power market regulators in the European Union (EU) have to comply with several constraints associated with EU policy and its move towards an integrated EU electricity market, known as the Target Model.[1] While the Target Model does not dictate the design of each jurisdiction's power market, it facilitates the adoption of a market design based on bilateral trading and self dispatch. Borggrefe and Neuhoff (2011) argue that bilateral trading with self dispatch limits the ability of regulators to monitor participants' bids and behaviour.

Regulators that cannot monitor participants' bids can still access other tools. Common market power mitigation tools include forward contract commitments for the output of the largest generators, behavioural rules (Joskow, 2008), or enhanced demand response (Borenstein and Bushnell, 1999). Lazar (2014) suggests that only a combination of tools will maintain a reliable and affordable electricity system, especially in the face of the increased penetration of unpredictable renewable electricity generation, which many EU markets are experiencing. In this paper we focus on the impact of short to medium term measures. The impact of forward contract commitments, changes in wind ownership and in demand response on the equilibrium wholesale electricity price. We do not include the effect of interconnection in this paper. Increases in interconnection are long-term solutions to market power problems. Malaguzzi Valeri (2009) showed that it would take high increases in interconnection capacity to significantly decrease market power in the SEM, assuming an efficient operation of the interconnector.

We take the Single Electricity Market (SEM) of Ireland and Northern Ireland as a test case and simulate market prices with the integrated electricity model PLEXOS,[2] which allows us to model strategic behaviour by generating companies. The SEM has several characteristics that are useful for our study. It is currently fully transparent with clear bidding rules designed

[1] The EU Third Energy Package created the regulatory framework underlying the shift to an EU-wide integrated electricity system.

[2] Available online at www.energyexemplar.com

to limit market power. Its transparency gives us access to information on the technical characteristics of all the plants including their heat rate curve, or the amount of fuel needed for each level of electricity generated. The SEM has limited interconnection to neighboring jurisdictions, allowing us to isolate the effect of changes in bidding strategies, forward markets and demand response more easily. Finally, it has a relatively large penetration of wind generation.

We simulate what would happen if all bidding rules were lifted, taking 2011 as the benchmark year. We find that, first, lifting all bidding rules leads to an increase in market power and increased prices, as expected. Second, we identify the theoretical effect of wind generation ownership on equilibrium prices, finding that ownership of wind generation by firms that also own thermal plants leads to increased prices. However, when we estimate the size of this effect, we find that it is small. Third, forcing the largest generator to sell part of its power forward has positive effects in theory, but limited effects on equilibrium prices when we simulate their effect for the SEM for reasonable levels of forward contracts. Fourth, increasing demand response can lead to significantly lower prices, although it is difficult to implement. We therefore conclude that regulators will have to remain vigilant and continue monitoring bids, although the lack of transparency in the Target Model will increase the market monitoring challenges.

In the next section we describe the state of the SEM, a competitive market, in 2011. Section 3 discusses the role of wind generation, forward markets and price elasticity of demand in the price formation of an oligopolistic market, using a simple two-firm setup. Section 4 introduces the simulations and section 5 discusses the results of the empirical analysis: the change in wholesale prices that could occur with strategic bidding with and without the three market power mitigation strategies.

2 The Single Electricity Market

The wholesale Single Electricity Market (SEM) of Ireland and Northern Ireland was established in 2007. Both jurisdictions were previously served by vertically integrated state-owned utilities. The SEM is a small market, serving a population of about 6.4 million in the 2011 reference year, with a large and increasing penetration of wind generation. Investors are free to decide what type of generation to invest in, given existing market conditions, but bidding behaviour is strictly regulated through the Bidding Code of Practice (Market, 2007).

Under its current market design, the SEM is a mandatory pool system where generators bid their short-run marginal costs (fuel, carbon, operational and maintenance costs) and receive the system marginal price in addition to capacity payments (Di Cosmo and Malaguzzi Valeri, 2014). Capacity payments in the SEM are designed to cover the cost of installing an additional unit of generation capacity. Plants bid in the day-ahead market and are stacked according to their bids, from the cheapest to the most expensive. They are called to generate in that order until they produce enough to service existing demand, accounting for each plant's technical constraints. The resulting electricity price does not take into account the transmission constraints or the capacity payments. The SEM operates within the EU and is therefore subject to the EU Emissions Trading System (ETS).

The regulatory authorities monitor the market through the Market Monitoring Unit. Power plants are required to bid their short run marginal cost in line with the bidding code of practice, based on day-ahead spot prices and receive the System Marginal Price (SMP). In addition to the SMP, which covers short-run costs of generation, generators receive capacity payments, designed to cover the cost of an additional unit of installed capacity. The market mimics perfect competition, as discussed in Market Monitoring Unit (2009) and Gorecki (2013) and verified in section 5.1.

In 2011 the SEM had only one interconnector between Northern Ireland and Scotland with a capacity of about 400 MW. Given the limited size of the interconnector, we do not take it into account during the market simulations. The 2011 SEM can be classified as an oligopoly with a competitive fringe. Two firms had a capacity share over 10%, as shown in Table 1, with 3 firms generating more than 10% of demand (demand is calculated as the sum of the generation of all the plants bidding into the market directly, interconnector flows and the generation of smaller wind farms that do not).[3] The largest firm is state-owned ESB, followed by AES, which owns the largest thermal plants in Northern Ireland.[4] Note that Bord Gáis owns a single thermal plant in 2011. We would expect it to have no advantage bidding strategically. However, we later show that its ownership of wind generation pushes it to bid strategically, although the effect of its bidding behaviour is quite small on

[3]Generation of the smaller wind farms is estimated by the transmission system operators: EirGrid in the Republic of Ireland and SONI in Northern Ireland.

[4]ESB is formed by ESB-PG, the incumbent in the Republic of Ireland, and ESB-International and we consider it a single firm. In 2012 the regulators let ESB bid as an integrated firm since the Bidding Code of Practice limited market power.

total wholesale prices. Wind linked to companies only through Power Purchase Agreements (PPAs) is excluded from the relevant company's strategic portfolio and it is assumed to be independent.

The SEM provides priority dispatch for a fixed amount of generation fuelled by peat. Peat is an indigenous fuel in the Republic of Ireland, with a low energy content. To secure this indigenous source, the government of Ireland guarantees a minimum yearly consumption of peat by power plants.

In 2011, due to large investments in renewable generation and the lingering effects of the financial crisis on electricity demand, the SEM displayed excess capacity, with a peak demand of 6,533MW compared to total capacity of 10,930MW (EirGrid and SONI, 2011).

Table 1: Market share by capacity and generation in the Single Electricity Market, 2011.

Firm	Capacity (MW)	Capacity Share (%)	Gen. share (%)
ESB	4166	38.1	43.7
AES	1830	16.7	11.0
Viridian	1011	9.3	12.4
Endesa	1016	9.3	0.2
Bord Gáis	672	6.1	8.3
Fringe-Thermal	835	7.6	8.6
Fringe-Renewables	1400	12.8	10.8
Net Imports	-	-	5.1
Total	10,930	100	100

ESB includes ESB-PG and ESB-I.
Capacity and market shares include wind ownership.
Dublin Bay is included in ESB-I's portfolio, as ESB-I owns 70% of its shares.
Datasources: SEMO, allislandproject.org, EirGrid, SONI, windpower.net.

In 2011 renewables (mostly wind) accounted for about 27% of total capacity, the sum of the renewable fringe in Table 1 and wind included in large firms' holdings. Table 2 shows that renewables (the sum of wind and hydro) generated about 17% of total demand. As in all EU countries, wind has priority dispatch.[5] The marginal cost of wind generation is close to zero, so when wind blows it is always profitable to generate. In practice, wind can be considered a price taker, because of the operation of the pool that ranks lowest to highest bidders. In section 3.1 we show, however, that wind can influence the bidding strategy of firms that own both wind and dispatchable generation.

[5]EU directive 2009/28/EC.

Table 2: Generation by fuel type and share of total demand, 2011

Fuel	GWh	Gen. share (%)
Natural Gas	19602	56.3%
Coal	5224	15.0%
Oil (incl. distillate)	185	0.5%
Peat	2079	6.0%
Hydro	693	2.0%
Wind	5259	15.1%
Other	98	0.3%
Net imports	1769	5.1%

Source: SEMO; EirGrid and SONI (wind); UKGrid (net imports)

3 Oligopolies and market power mitigation: a simple model

In this section we present a simplified two-generator model to highlight how generators' behaviour and market mitigation measures will affect wholesale electricity prices. To model the oligopolistic aspect of the market we use a Cournot framework, with a competitive fringe that encompasses the increasing number of price takers on the market (including wind generators and combined heat and power plants).

The assumption of Cournot competition, where firms bid the quantities of electricity they will generate in each period, is a simplification. When there are capacity constraints and demand is rationed efficiently, the Cournot outcome mimics a two step game where firms choose capacity in stage one and compete in prices (à la Bertrand) in stage two (Tirole, 1988). Some of the strong assumptions needed to obtain the Cournot equilibrium in the two-part game are verified in the case of electricity markets: electricity is a non-differentiated good, capacities are observable by all, capacity costs are relatively large and bids are set simultaneously. This explains why the Cournot competition framework has often been used to analyse outcomes in electricity markets, both in Europe and the US (see Wolfram, 1999, Bushnell, 2007, Borenstein et al., 1999). In turn, we study the effect of changes in wind generation ownership, forward contracts and price elasticity of demand.

3.1 Wind generation ownership

We first highlight the difference in prices in the competitive scenario versus the Cournot one assuming that all wind generation is competitive. We then address the effect of accounting for ownership of wind generation.

Assuming that all wind is competitive, Twomey and Neuhoff (2010) and Browne et al.

(2015) show that in the short run increased wind generation decreases market power (and therefore prices) in periods when wind blows heavily. On the other hand, it may increase market power and prices at times of low wind. Long run effects depend on how returns to investment for thermal plants evolve over time. Browne et al. (2015) suggest that if increased wind leads to lower investment in thermal plants, especially in peaking units, in the long run it may drive higher market power in periods when wind blows weakly. Here we focus not on the effect of increased wind generation per se, but on the effect of wind ownership on the price in an oilgpopoly setting.

We assume that there are 2 symmetric firms, each with total cost function $C^j = q_j^2/2$, and increasing marginal costs (MC) $c^j = q_j$, $\forall j$. We also include fixed capital costs F_j in firms' profit functions. The firms face a (inverse) linear demand curve $P = a - b \cdot Q$ for every period, where $P(0) > 0$.

To simplify the analysis, we limit the competitive fringe to 0 marginal cost producers in the following example. Such producers will offer generation on the market any time the price is non-negative. The sum of all the price-taking output at time t is represented by Q_t^F.

Each strategic firm j chooses the generation quantity in each period to maximise its expected profits Π_j.

$$\max_{q_j} \Pi_j = (a - b \cdot Q) \cdot q_j - q_j^2/2 - F_j \qquad \text{where } Q = \sum_j (q_j) + Q^F \tag{1}$$

The first order condition for each firm j yields the following equilibrium quantity:[6]

$$q_j = \frac{a - b \cdot Q^F}{(1 + 3b)} \tag{2}$$

with corresponding Cournot equilibrium price:

$$P^C = \frac{(1 + b)(a - b \cdot Q^F)}{1 + 3b} \tag{3}$$

The larger the competitive fringe Q_t^F, the lower the equilibrium price will be.

We can compare the price in Cournot to the price that would occur in perfect competition, where $P = MC$. In equilibrium, the marginal cost is the same for both firms ($MC_i = MC_j = \overline{MC}$) and the equilibrium price will be equal to the common marginal cost, $P(q_i + q_j + Q^F) =$

[6]The second order condition for a maximum is also met.

$\overline{MC}$, leading to:

$$P^* = \frac{a - b \cdot Q^F}{1 + 2b} \tag{4}$$

P^C is always larger than P^* as the difference between the two is greater than 0:

$$P^C - P^* = \frac{(1+b)(a - b \cdot Q^F)}{1 + 3b} - \frac{a - b \cdot Q^F}{1 + 2b} = \frac{2b^2(a - b \cdot Q^F)}{(1+3b)(1+2b)} > 0 \tag{5}$$

Equation 1 shows the profit maximization function of a firm operating as a Cournot competitor in an environment that has a fringe of price-taking firms, including wind generators. What happens when some of the wind is owned by firms that bid strategically? We assume that the marginal cost of wind generation is 0, that both generators own wind and continue assuming that the firms are symmetric, so that each strategic firm owns an equal amount of wind generation, which we denote $\frac{q^w}{2}$. The fringe generation is therefore $Q^F = Q_0^F$, where Q_0^F is the amount of wind owned by independent generators, and wind generation is the sum of Q_0^F and q^w.

Each firm generates a quantity of electricity denoted by $q_j + \frac{q^w}{2}$. The profit maximizing function for strategic firm 1 becomes the following:

$$\max_{q_1} \Pi_1 = [a - b \cdot (q_1 + q_2 + q^w + Q_0^F)] \cdot (q_1 + \frac{q^w}{2}) - q_1^2/2 - F_1 \tag{6}$$

and similarly for symmetric firm 2. Note that the firm cannot choose the amount of q^w since wind generation is not dispatchable. Also,when wind is available it will be optimal for the firm to bid it in. This however does not exclude that wind ownership will affect the optimal thermal quantity a generator bids into the market. Because any existing wind will benefit from higher prices, there is an added incentive to owners of both wind and thermal generation to decrease the quantity of dispatchable (thermal) generation offered in the market.

The first order condition (FOC) for maximisation is

$$q_1 = q_2 := \hat{q} = \frac{a - b(\frac{3}{2}q^w + Q_0^F)}{1 + 3b} \tag{7}$$

As wind generation increases, strategic firms decrease the optimal amount of thermal generation.

Substituting the equilibrium amounts in the Cournot price function $P^C(q^w) = a - b \cdot (q_1 +$

$q_2 + q^w + Q^F$)) yields:

$$P^C(q^w) = a - b \cdot [2\hat{q}(q^w) + q^w + Q_0^F] \quad (8)$$

How does P^C vary with quantity of wind owned by a strategic firm? Using comparative statics, we can define the effect on the equilibrium price of a change in q^w by differentiating Equation 8 with respect to q^w.

$$\frac{dP^C}{dq^w} = -2b \cdot \frac{d\hat{q}}{dq^w} - b = \frac{-b}{1+3b} < 0 \quad \forall b > 0. \quad (9)$$

We compare this to the change in the equilibrium Cournot price when additional wind is owned by independent generators, that is when Q_0^F increases. Differentiating equation 8 with respect to Q_0^F yields the following:

$$\frac{dP^C}{dQ_0^F} = \frac{-b(1+b)}{1+3b} \quad (10)$$

If we compare equation 9 to equation 10, we see that when wind is owned by strategic firms the equilibrium price decreases less: $|\frac{dP^C}{dq^w}| < |\frac{dP^C}{dQ_0^F}|$. This finding is consistent with Ben-Moshe and Rubin (2015), who take a slightly different approach.

3.2 Forward contracts

How does the oligopoly equilibrium on the spot market change if the regulators force generators to sell some of their product forward? There is a broad literature that considers forward markets as endogenous, allowing generators to yield market power both in the spot and in the forward market (see e.g. Mahenc and Salanié, 2004, Green, 1999). In this paper we focus on the case where regulators determine both price and quantity sold forward, thereby eliminating the possibility of market power in the forward market. Regulating the price of forward sales is a solution adopted in a few markets, mostly through virtual power plant (VPP) auctions (see Ausubel and Cramton, 2010, Creti et al., 2012), although a few of these auctions have been recently eliminated, e.g. the VPP auctions in Spain that ended in 2009 (Federico, 2010). In the SEM, whereas generators are free to sell forward a larger volume than dictated by the regulators, in practice they do not.[7]

[7] One explanation for this behaviour is that the spot market is fully hedged, as all the costs are passed on to final consumers, thereby providing limited incentives to trade forward. Other possible explanations are tied to the small size of the market: there are fixed transaction costs associated with trading in forward markets and in the SEM there may be a lack of interested buyers.

de Frutos and Fabra (2012) show that the price of forward contracts makes no difference on firms' bidding behaviour in the spot market when forward contract prices are exogenous, although it affects firms' profits.

Assume that only one firm is forced to sell x_i forward contracts, say firm 1, at price τ_1. In that case the objective function for firm 1 will become to maximise profits where the equilibrium price is P^* and F is the amount of electricity sold forward:

$$\max_{q_1} \Pi_1 = P^* \cdot (q_1 + \frac{q^w}{2}) - q_1^2/2 - F_1 + (\tau_1 - P^*)x_1 \tag{11}$$

Forward contracts often take the form of contracts for differences, where the seller pays (or is paid) the difference between the forward contract price and the spot price. The contracts for difference can be thought of as strictly financial contracts. In any given period a firm can sell more or less than the amount it generates, although in practice x_1 will be smaller than the firm's competitive output. Remember that x_1 is determined by the regulator and is explicitly used to mitigate market power. The regulator will not force a firm to sell more than its theoretical production. The amount sold forward is sold to the suppliers of final consumers who continue to buy all of their electricity on the market at the spot price. Similarly, the firm continues to sell all its electricity on the spot market. If the spot market price is larger than τ_1, generators will pay the difference between P^* and τ_1 to consumers. Consumers will pay the difference to generators if the spot market price is lower than τ_1.

This can be rewritten as:

$$\max_{q_1} \Pi_1 = [a - b \cdot (q_1 + q_2 + q^w + Q_0^F)] \cdot (q_1 + \frac{q^w}{2} - x_1) - q_1^2/2 - F_1 + \tau_1 x_1 \tag{12}$$

Since τ_1 will not influence the spot market equilibrium, its level does not matter for this analysis, although it will influence firms' profits.

We are assuming that only firm 1 is subject to forward contracts. The Cournot equilibrium quantity for firm 1 (subject to contracts) can be expressed as:

$$\hat{q_1} = \frac{a - b(\frac{3}{2}q^w + Q_0^F)}{1 + 3b} + \frac{b(q + 2b)x_1}{(1 + b)(1 + 3b)} \tag{13}$$

Note that this is the same expression as in Equation 7, except that the equilibrium quantity for Firm 1 increases with the amount of contracts sold forward x_1.

Calculating the equilibrium for Firm 2 and substituting in the expression for the equilibrium price gives the following expression:

$$\hat{P} = \frac{a(1+b) - bq^w - b(1+b)Q_0^F}{1+3b} - \frac{2b^3}{(1+b)(1+3b)}x_1 \tag{14}$$

The main finding is that the Cournot equilibrium price decreases as the amount x_1 sold forward by firm 1 increases:

$$\frac{dP^C}{dx_1} = -\frac{2b^3}{(1+b)(1+3b)} < 0 \tag{15}$$

This intuition remains true with more complex representations of the interactions between firms. Using supply function equilibria, de Frutos and Fabra (2012) conclude that in power markets with one dominant player, forcing the largest player to sell some if its electricity forward will always be pro-competitive in the spot market (i.e. the price will decrease) .[8]

In our simulations, we explore different levels of forward sales for the largest generator and investigate how they affect the spot price.

3.3 Price elasticity of demand

Finally, we observe that when the sensitivity of electricity demanded to price increases, the Cournot mark-up with respect to the competitive price decreases. Bushnell (2007) summarises the literature to show that with symmetric firms, the price-cost margin (the Lerner Index) is proportional to $1/\epsilon$, where ϵ is the price elasticity of demand, p is the price, mc is the marginal cost and n is the number of oligopolistic firms in the market.

$$\frac{p - mc}{p} = \frac{1}{n\epsilon} \tag{16}$$

When the firms are not symmetric, the intuition stays the same. The more sensitive demand is to changes in price, the lower the price-cost margin in equilibrium.

Our simulations suggest that increasing demand sensitivity to price provides clear benefits in terms of limiting market power. We recognize that increasing demand sensitivity is not easy. In general, retail prices tend to change infrequently, providing consumers no incentives

[8] If firms are similarly sized, forward contracts may help to maintain collusion in the spot market. Murphy and Smeers (2010) shows that the pro-competitive effect may not arise if firms are capacity-constrained. Liski and Montero (2006) and Ressner et al. (2010) show that with an infinite horizon, the pro-competitive effect also disappears, although in their models the size of forward sales is chosen by the firms, not the regulator.

to adjust consumption in the short run. Electricity market operators and regulators have tried to increase the sensitivity of electricity demand to price, in part to control market power and in part to enable integration of intermittent renewables. In the US, the attempt to include demand resources in wholesale electricity markets was encouraged by FERC regulation 719, although many of the demand response measures put in place are not price based, thereby limiting the effect on price elasticity of demand (Bushnell et al., 2009).

Overviews of demand response measures in the US and Europe highlight the technical, operational and economic challenges in moving towards a more responsive demand (O'Connell et al., 2014, Torriti et al., 2010, Faruqui et al., 2015). Technical challenges include the need to establish reliable control strategies (O'Connell et al., 2014). Operational challenges include the difficulty moving away from fixed retail prices to time-varying prices, although this may be easier for industrial consumption (Torriti et al., 2010). Many jurisdictions are trying to increase demand response, in part with the goal of accommodating more intermittent renewable generation. With this goal in mind, Lazar (2014) proposes a combination of technological and market measures to increase demand response, such as improved demand response markets, higher prices at times of high demand increases, inclusion of more storage on the system and greater interconnection with neighboring systems.

4 Data

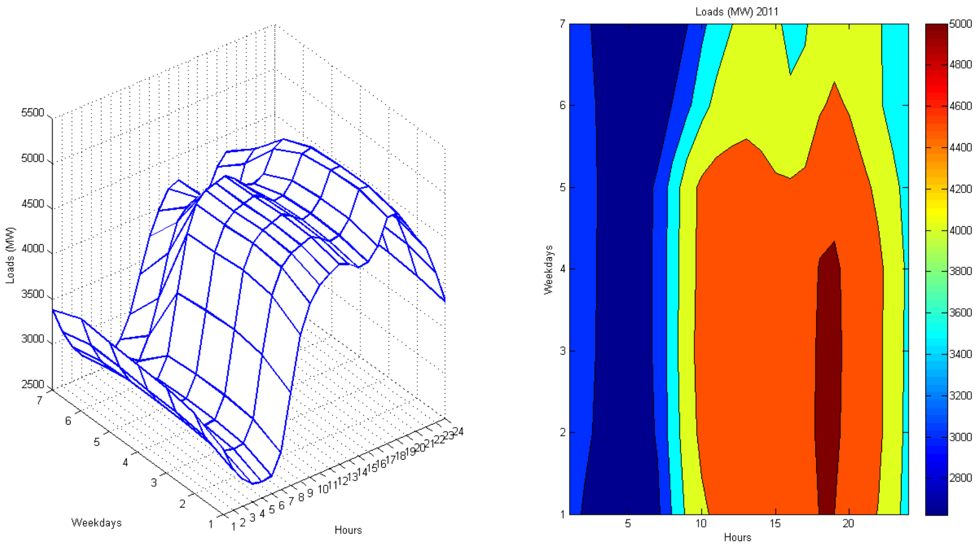
4.1 Demand and wind

The historical demand for 2011, net of interconnector flows, comes from EirGrid and SONI, the transmission operators in the Republic of Ireland and Northern Ireland respectively. In the SEM, the yearly peak hours are from 5 p.m. to 7 p.m. in the winter, whereas during the summer it is earlier, typically between noon and 2 p.m. Figure 1 shows demand in each hour of the day, by day of the week, averaged across the full year. The SEM is fairly small, with an average peak demand of around 4.5GW and a peak demand on cold December afternoons of about 6.5GW.

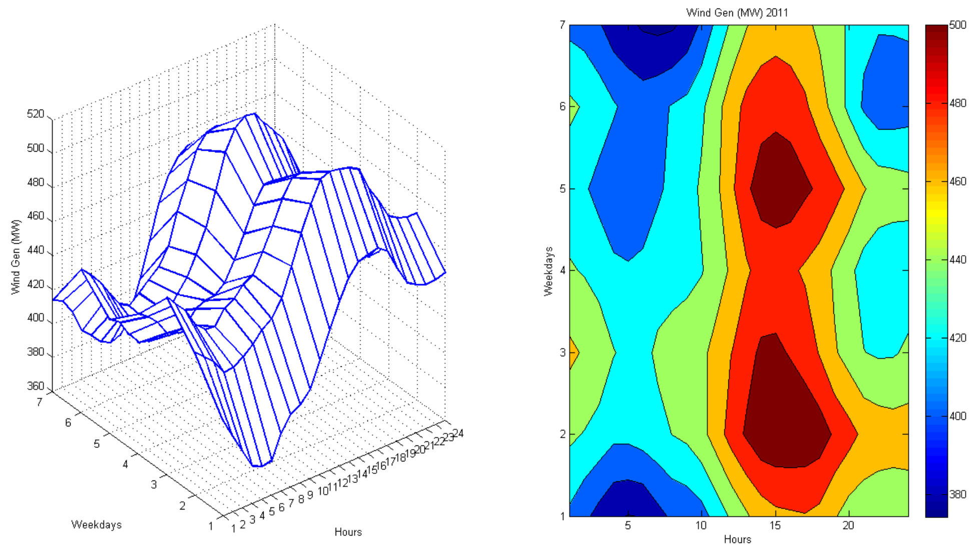
Wind generation is estimated by EirGrid and SONI. The level of wind we use in these simulations includes both wind that bids into the market and smaller wind farms.[9] Average hourly wind generation by day of week is correlated with the load, although peak wind

[9] In 2011, including the smaller wind farms increases reported wind generation by about 25% on average.

generation is around 3 p.m., a few hours before the load peak. However, when we examine the correlation between load and wind generation at the half-hourly level the correlation disappears, with a coefficient equal to 0.14 in 2011.



(a) SEM average hourly loads, 2011, MW



(b) SEM average wind generation, 2011, MW

Data sources: SEMO, EirGrid and SONI

Figure 1: Average loads and wind in the SEM in 2011, MW

4.2 Price elasticity of demand

Demand for electricity responds to (retail) prices. We use sectoral estimates of the Price Elasticity of Demand (PED) for Ireland from Di Cosmo and Hyland (2013). The estimates by sector are combined with the electricity consumption share by sector from the SEAI National Energy Balances[10] to estimate the average PED for electricity in Ireland. We implicitly assume that numbers for Northern Ireland are similar. Table 3 shows an average PED for electricity of $e = -0.16$, consistent with international estimates (see Table 1 in Fan and Hyndman, 2011). This is an upper bound of the PED for wholesale prices, since wholesale prices are a fraction of final retail prices. The implied wholesale PED, based on wholesale's share of retail prices for 2011 (as reported by Eurostat) is equal to $e = -0.11$. In the simulation section we report the main results for $e = -0.11$ and a sensitivity analysis for $e = -0.16$ and $e = -0.30$.

Table 3: Price Elasticity of Demand by Sector, Ireland.

Sector	Consumption share	PED	PED*Share	Wholesale price as a share of retail price	Wholesale PED
Industrial	38%	-0.275	-0.105	76%	-0.080
Residential	33%	-0.07	-0.023	55%	-0.013
Commercial	26%	-0.09	-0.024	55%	-0.013
Agriculture	2%	-0.38	-0.009	55%	-0.005
Weighted PED			-0.16		-0.11

Consumption share from SEAI National Energy Balances for 2011 (see footnote 10).
Elasticity by sector from Di Cosmo and Hyland (2013).
Wholesale price shares from Eurostat.

The lower values are in line with the hourly price elasticity of demand in the Ontario (Canada) wholesale market (Genc, 2016). The author finds that the hourly price elasticity of demand in the Ontario wholesale market is on average around 0.13 in absolute value and is higher in the winter than in the summer.

4.3 Fuel prices

The fuel prices included in the simulation are historical 2011 spot market prices, used by generators to build their bids. Gas prices are the same for the Republic of Ireland and Northern Ireland as gas is imported from GB through a common interconnector. Given that gas has a pronounced seasonality, we include different prices by quarter. Distillate oil prices vary by month and Table 4 reports their quarterly average. All other fuels have a single price over the year. Moneypoint, the coal plant in the Republic of Ireland, obtains a lower

[10] Available at `http://www.seai.ie/Publications/Statistics-Publications/Energy-Balance/Previous-Energy-Balances/`

price per tonne of coal than Kilroot, the coal plant in Northern Ireland. Moneypoint can accommodate larger ships thanks to its deeper port, so we report the average price for the two plants separately.

Table 4: Fuel prices, €/GJ, 2011

	Gas	Coal		Peat	Distillate
		RoI	NI		
Q1:Jan-Mar	6.20				16.60
Q2:Apr-Jun	5.98				17.62
Q3:Jul-Sep	5.65				17.25
Q4:Oct-Dec	6.74				17.49
Average	**6.14**	**3.94**	**4.47**	**3.75**	**17.24**

5 Simulations

This section reports the change in wholesale electricity prices in the SEM when firms bid strategically, in the presence of three conditions that may influence firms' strategies: changes in the ownership of wind farms, the existence of a compulsory forward market for the largest firm and changes in demand response. It compares the prices to the perfectly competitive price.

We use Energy Exemplar's PLEXOS (version 7.3) Integrated Energy Model and the Xpress Mixed Integer Programming solver[11] to simulate SEM wholesale electricity prices for 2011. PLEXOS is a modelling tool used for electricity market modelling and planning. The model optimises thermal and renewable generation and pumped storage subject to operational and technical constraints at an hourly resolution. The objective function is to minimise total costs over the year across the full system including: operational costs, consisting of fuel costs and carbon costs; start-up costs consisting of a fuel offtake at start-up of a unit; and a fixed unit start-up cost. A detailed description of the model and the model equations can be found in Deane et al. (2014).

5.1 Perfect competition

We start by assuming that firms are price takers, i.e. they do not engage in strategic behaviour. Table 5 reports the simple average of the system marginal price (SMP). For comparison, we also include the historical average. The historical price is close to the simulated

[11] FICO Xpress Optimizer, available at http://www.fico.com

perfectly competitive price, with the historical price about 3 per cent higher than the simulated one and displaying a slightly lower variance. This confirms that the curent market is close to perfectly competitive in line with expectations, since bidding in the SEM is currently strictly regulated.

Table 5: Perfect competition short-run price, historical and simulated, 2011 €/MWh

	Mean	St.Dev.	Min	Max
Simulated Perfect Competition SMP	*59.7*	*34.9*	*6.8*	*559.4*
Historical SMP	61.8	32.5	0.0	487.5

The reported mean is the simple average.
Simulated values in italics.

The system marginal price (SMP) summarises the short run costs of generating electricity and includes fuel, carbon and operation and maintenance costs. In addition generators receive capacity payments, which were on average equal to €16.2/MWh in 2011 (Deane et al., 2015). The sum of the SMP and capacity payments is a measure of the long-run costs of generating electricity. Table 6 reports the long-run price as the sum of capacity payments and the short-run values, weighted by demand. These numbers are slightly higher than those reported in 5 (where the price was not weighted by demand) since the price tends to be higher when demand is larger.

Table 6: Perfect competition long-run price, historical and simulated, 2011 €/MWh

	Price
Historical SMP, weighted avg.	65.0
Simulated SMP, weighted avg.	*62.8*
Capacity Payments	16.2
Historical Perfect Competition, long run	81.2
Simulated long-run perfect competition price	*79.0*

SEMO, EirGrid and SONI. Capacity payments from Deane (2015)
Reported averages are weighted by demand.

To investigate what happens when the regulator is unable to monitor bids closely, we relax the assumption of perfect competition. We compare the prices that emerge when firms bid strategically to the simulated long run marginal price of €79.0/MWh reported in the last row of Table 6. Note that when we estimate the equilibrium price with strategic firms, we do not add any capacity payments. In energy-only markets the price is designed to cover both short and long run cost of generating electricity. The energy-only price will always be larger than the short-run cost in the competitive scenario. The question we examine here is how much larger the energy-only price is in the presence of both market power and measures that could affect market power: different wind ownership patterns, forward contracts and increased demand response.

5.2 Cournot competition with varying wind ownership

In section 3.1 we showed that the distribution of wind ownership influences the strategic bids of thermal plant owners. In this section we verify how large the effect on wholesale prices is in response to variations in wind ownership.

We compare the wholesale price of electricity in 3 scenarios. In the first, all wind is considered independent (i.e. is not associated with any thermal generator). In the second, firms with more than one thermal plant are assumed to bid strategically and include their wind holdings when setting their optimal bid. In the third scenario, all thermal plant owners (including Bord Gáis that owns a single thermal plant in 2011) bid strategically and include wind holdings when setting their bid. Wind, hydro and biomass generators not owned by one of the major firms are assumed to be price takers. Peat plants are also price takers since they have priority dispatch in the SEM.

In 2011 about 62% of wind capacity was owned by independent operators. The remaining 38% belonged to companies that also owned thermal plants, as shown by Table 7. Wind linked to companies only through PPAs is excluded from the relevant company's strategic portfolio and is assumed to be independent. The information on wind capacity ownership comes from the Irish Wind Energy Association's (IWEA) (www.iwea.com). We expect that including wind ownership in thermal plants' portfolio will increase the equilibrium price with respect to the case when all wind is independent, in line with the modelling results in section 3.1.

Table 7: Wind ownership, 2011

Company	Share (%)
Viridian	17
Bord Gais	12
ESB	9
Wind Indep.	62

Table 8 shows that when all wind is independent, the price in the Cournot equilibrium increases to an average €129.1/MWh or 63% above the perfectly competitive price. This suggests that a sizeable amount of wind (around 15% of total demand) is not sufficient on its own to bring prices close to their competitive levels, given the SEM's market structure and in the absence of additional measures.

When we include the effect of wind ownership on firms' bids, the wholesale price increases a little more, to €130.5/MWh. The direction of the change is as expected, but the size of the change is not very large, in part because more than 60% of wind remains independent in both scenarios. Note that there is no difference between the scenario where all wind is independent and the one where all thermal plant owners other than Bord Gáis account for wind ownership when optimising bids, highlighting that the effect of wind ownership is quite small in practice. The effect of wind ownership on Bord Gáis' bids is likely due to wind's large share of Bord Gáis' total capacity: wind increases Bord Gáis' capacity from 438MW to 672MW, representing 35% of its capacity. We therefore conclude that increasing strategic firms' wind ownership up to 40% of available wind capacity does not significantly add to the risk of high market power in the SEM.

Table 8: SMP, with and without strategic wind, 2011, €/MWh

	Wholesale price	% Difference LRPC
Long-run Perfect Competition (LRPC)	79.0	-
All wind independent	129.1	63
Historical wind ownership	130.5	65
Bord Gáis wind independent	129.1	63

Averages are weighted by demand

5.3 Forward contracts

We compare how prices change when the regulators impose different levels of forward sales on the dominant generator, ESB. We start by comparing the Cournot outcome without forward contracts to the scenario where ESB sells about 10% of its generation forward. This corresponds to the historical amount of forward contracts imposed by the regulator in 2011 and is equivalent to an average of about 307MW of forward contracts per hour. Table 9 shows the precie amount of generation we assume is sold forward in each scenario. Baseload electricity is generated at any time of the day, midmerit is generated between 7:00 and 23:00 and peak is generated between 17:00 and 21:00 during the months of October to March, both included.[12] We build the 2GW and 3GW scenarios assuming a distribution between baseload,

[12]The regulators also distinguish between business and non-business days for midmerit forward contracts, but we assume the same amount in all days of the week in the reported scenarios.

midmerit and peak that is proportional to the 2011 historical one. We assume that the sum of all contracts types is constant across quarters.[13]. We include a fixed contract price for all forward contracts of €80/MWh, although note that changes in the contract price imposed by the regulator will have no effect on the spot price since the price is exogenously set, as discussed in section 3.2. The contract price will have an effect on the profits of firms that sell forward, but that is not the focus of this paper. In each of these scenarios, only ESB is selling forward. All other strategic generators bid strategically in the spot market with their full capacity.

Table 9: ESB forward contract scenarios by quarter in MW

	2011 historical			2GW			3GW		
Quarter	BL	midmerit	peak	BL	midmerit	peak	BL	midmerit	peak
Q1	0	155	202	0	868	1132	0	1303	1697
Q2	0	312	0	0	2000	0	0	3000	0
Q3	0	211	0	0	2000	0	0	3000	0
Q4	209	104	36	1198	596	206	1797	894	309

BL=baseload: 24 hours a day; midmerit from 7:00 to 23:00;
peak from 17:00 to 21:00 between October and March.

Table 10 shows that when ESB sells an amount of electricity forward similar to the 2011 historical amount, prices in the strategic scenario decrease only slightly (to €129.1/MWh) with respect to the case with no forward contracts (€130.5). When the level of forward contracts increases more than six fold, to 2GW on average per period, the spot price decreases by €11, to €119.4/MW, still 51% above the long-run perfectly competitive price. Finally, for the 3GW scenario (about a ten-fold increase from the historical level), the spot price decreases to €106.4/MW, staying about 35% above the long-run perfectly competitive price.

Table 10: Simulated SMP, with and without forward contracts, 2011, €/MWh

Scenario	Wholesale price	% Difference LRPC
Long-run Perfect Competition (LRPC)	79.0	-
No forward sales	130.5	65
2011 Historical forward sales	129.1	63
2GW forward sales	119.4	51
3GW forward sales	106.4	35

Averages are weighted by demand

We conclude that the spot price goes in the expected direction when forward contracts are imposed by the regulator. However, the effect of forward contracts on the largest generator is not very large for realistic levels of forward contracts. Increasing the amount of contracts

[13]Historically quarter 3 had a lower forward contract amount

more than six-fold (the 2GW scenario) decreases spot prices by €11/MWh, or less than 10%. Increasing the forward contracts more than ten-fold (representing close to all of ESB's generation) decreases prices by about 18%. On its own, therefore, this measure does not eliminate the risk of abuse of market power. One explanation of this result is that as more and more of the dominant's firm generation is sold forward, other generators can influence the equilibrium price, so the market never approaches the perfectly competitive outcome.

5.4 Demand response

The final set of scenarios explore the effect of increasing demand response on equilibrium prices. We assume that the elasticity of demand varies between -0.11 and -0.3. In particular, we focus our analysis on three elasticity scenarios: -0.11, -0.16 and -0.3.

Table 11 shows that increasing the price elasticity of demand from -0.11 to -0.16 decreases the equilibrium price in a Cournot scenario by €20/MWh. A large increase of the price elasticity of demand to -0.3 would lead to equilibrium wholesale prices that are only 10% larger that the perfectly competitive outcome, even without enacting any other measures.

Table 11: SMP and demand response, 2011, €/MWh

Elasticity	Wholesale price	% Diff. wrt long-run PC
-0.11	130.5	65
-0.16	109.6	39
-0.3	86.6	10

All prices are weighted averages

The LRPC price assumes elasticity = -0.11

The theoretical improvements in the market with a more elastic demand are appealing and several jurisdictions are increasing their efforts to improve demand response. Price elasticity of demand may increase in the medium to long term, as distributed storage becomes cheaper and time-of-use tariffs and smart meters become more widespread. However, as discussed in section 3.3, there is evidence that inducing a more elastic demand in the short run is challenging. Increasing the responsiveness of demand to hourly prices as a minimum involves new infrastructure (smart meters) and more flexible retail prices.

6 Conclusions

This paper highlights the challenges associated with moving to a fully deregulated electricity wholesale market. In many jurisdictions the generation sector is characterised by a limited number of large firms, enabling the emergence of market power and its associated high prices. Electricity markets are at particular risk of abuse of market power since electricity is not easily stored, entry is costly and demand is relatively inelastic.

This paper explores three measures that may influence market power in wholesale electricity power markets: changes in ownwership of wind generation, increases in the share of electricity generation sold forward by the largest generator and increases in the price elasticity of electricity demand. We find that greater wind ownership by thermal generators does not affect prices strongly. While wind ownership by thermal plant owners increases wholesale prices, in line with the theoretical findings, it does so by a small amount.

Increasing the amount of generation that the largest firm has to sell forward decreases the wholesale spot price, as expected. However, we find that for reasonable levels of forward contracts, the effect on spot prices is not very large. One explanation is that as the incentive to bid strategically decreases for the largest firm, it increases for the other oligopolists. Finally, increasing the price elasticity of demand has a large theoretical impact on wholesale prices. It is the only measure that on its own brings prices close to their perfectly competitive level. However we highlight that there are challenges to creating a more elastic demand, especially in the short run. As a minimum, creating a more elastic demand involves the deployment of smart meters and the adoption of time-varying retail prices.

There are reasons to think that the simulation results presented here should be considered upper bounds on the price that would be realised in an oligopolistic SEM market. First of all, our analysis is based on a static environment. In practice firms will consider dynamic incentives when bidding. For example, firms might recognise that if prices increase, the risk of regulatory intervention or new entry by firms may also increase. Second, the results reported in Table 8 assume that imports are frozen at their historical level. The interconnection with Great Britain doubled in 2012, with the commissioning of the East-West interconnector and we expect that large increases in the SEM wholesale price would lead to somewhat larger imports of electricity. On the other hand, 2011 was a year when the SEM displayed excess capacity, due in part to the continuing effect of the financial crisis on electricity demand. As demand recovers we can expect more periods when generating firms would be able to exercise market power.

Overall, the analysis suggests that for a market as the SEM, there is a risk that decreasing regulatory oversight will produce a significant increase in marginal wholesale prices. We conclude that regulators will have to continue monitoring bids in the market, which will be more difficult due to its lack of transparency. They should also consider putting in place the infrastructure and regulations needed to increase the price elasticity of wholesale electricity demand.

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